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Baseload electricity from wind via compressed air energy storage (CAES)

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ABSTRACT

This study investigates two methods of transforming intermittent wind electricity into firm baseload capacity: (1) using electricity from natural gas combined-cycle (NGCC) power plants and (2) using electricity from compressed air energy storage (CAES) power plants. The two wind models are compared in terms of capital and electricity costs, CO_2 emissions, and fuel consumption rates. The findings indicate that the combination of wind and NGCC power plants is the lowest-cost method of transforming wind electricity into firm baseload capacity power supply at current natural gas prices (~$6/GJ). However, the electricity supplied by wind and CAES power plants becomes economically competitive when the cost of natural gas for electric producers is $10.55/GJ or greater. In addition, the Wind-CAES system has the lowest CO_2 emissions (93% and 71% lower than pulverized coal power plants and Wind-NGCC, respectively) and the lowest fuel consumption rates (9 and 4 times lower than pulverized coal power plants and Wind-NGCC, respectively). As such, the large-scale introduction of Wind-CAES systems in the U.S. appears to be the prudent long-term choice once natural gas price volatility, costs, and climate impacts are all considered.

Contents

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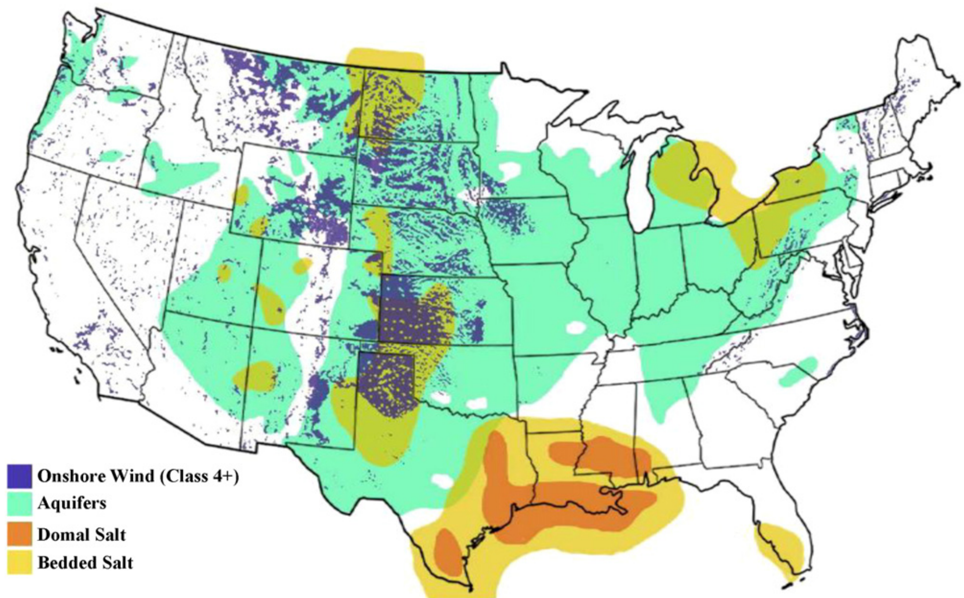


Fig. 1. Map of U.S. showing areas with Class 4 or higher wind resources and areas with geology suitable for underground air storage reservoirs. Reproduced with permission from Succar [10].

1. Introduction

The U.S. is endowed with abundant wind energy resources, both onshore and offshore [1–5]. However, electricity supplied by wind is intermittent and traditionally has required the deployment of thermal power plants (mostly natural gas combined-cycle, hereafter NGCC) to firm it, i.e., to convert it into a reliable supply of electricity that is available on demand. This study investigates the use of an alternative method to firm wind-generated electricity: storage via compressed air energy storage (CAES). The two approaches, traditional (via NGCC power plants) and storage (via CAES), are compared in terms of capital cost, cost of electricity, fuel consumption, and carbon dioxide (CO_2) emissions.

Whereas prior studies have investigated the use of CAES in combination with wind electricity in general terms [6–11], this study focuses on a specific, practical scenario: a 20% wind penetration level for total U.S. electricity by 2030. This level of penetration represents an average of the targets of various states' Renewable Energy Portfolio Standards and is in line with projections by the National Renewable Energy Laboratory (NREL) and the Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) [1].

NREL studied the integration and transmission of U.S. wind power at the 20–30% penetration level by 2030 and concluded that energy storage is not needed since natural gas thermal power plants can be employed to firm variable wind electricity at a lower cost than storage, including CAES [12,13]. These NREL reports are the first planning step toward the development of a national electricity transmission system designed for the U.S. to integrate large quantities of wind electricity into the nation's power mix. However, they did not analyze the corresponding increase in natural gas consumption and its associated long-term economic and climatic impacts.

An analysis of natural gas consumption rates is needed because of the large quantity of wind electricity generation being considered at a 20% penetration level: ~800 terawatt-hours (TWh) from wind in a year, which corresponds to ~300 gigawatts (GW) of wind capacity and requires ~72 GW of additional natural gas power plant capacity, if the traditional thermal approach is taken [12].

This paper extends past studies by including these "hidden" natural gas requirements when the thermal approach (via natural gas combined-cycle power plants) is taken versus the storage approach (via CAES) to firm a 20% penetration of wind electricity. When all factors, from economic to climatic, are included, the conclusion is actually opposite: storage via CAES is found to have lower total costs and lower climatic impacts than the traditional thermal approach. Other means of firming wind power supply via storage, such as pumped-hydro and batteries, are not considered in this study.

2. Baseload power plant models

Coal power plants provide about two-thirds of baseload electricity and about half of total electricity supply in the U.S. [14]. The typical power capacity of coal power plants is 400 MW, with a range of 300–600 MW, and their average operating efficiency is 37%. CO_2 emissions from coal power plants are very large in the U.S., about 80% of the CO_2 emissions by the electric power sector and 33% of total energy related CO_2 emissions.

This study evaluates two wind models that are designed to replace baseload coal plants and thereby reduce CO_2 emissions: (1) traditional method, in which wind power is supported by electricity supplied by natural gas combined-cycle power plants (Wind-NGCC); and (2) storage method, in which wind power is supported by electricity from compressed air energy storage (Wind-CAES). These two wind models are compared against baseload coal power plants when relevant. Descriptions of the models are presented below.

2.1. Wind power and transmission calculations

To minimize the retail price of wind electricity, it is assumed that wind farms are located in areas with Class 4 or higher wind regimes. The largest onshore source of Class 4 and higher wind resources in the U.S. is in the high plains from the Canadian border to the Texas Panhandle (Fig. 1). Wind power can then be distributed to all areas east of the Rocky Mountains via the transmission grid. High-quality wind resources west of the Rocky Mountains can be utilized for the western U.S. Evaluation of offshore wind power,

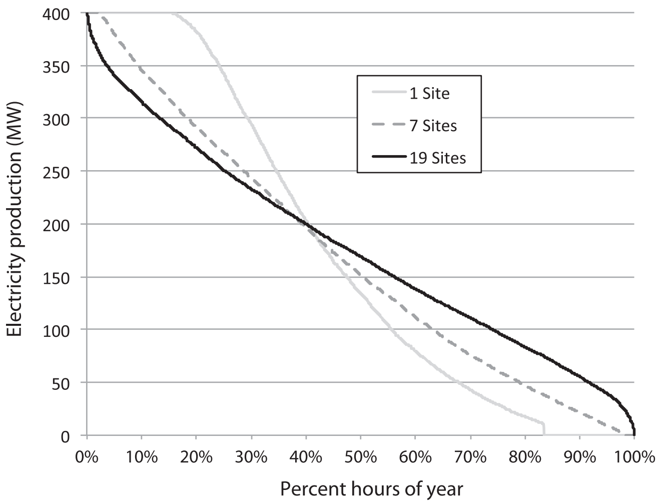


Fig. 2. The effect of interconnecting geographically dispersed wind plants on aggregate power supply.

which currently has higher costs than onshore [15], is beyond the scope of this study.

Hourly wind electricity production is estimated with the Archer and Jacobson wind dataset [16]. The dataset contains hourly wind speed at 80 m above the ground, the hub height of modern wind turbines, at 19 Class-4 locations in the Midwest in the year 2000. It is assumed that GE 1.5 MW wind turbines are installed at the 19 sites and that the 19 sites can be interconnected via the transmission grid. The wind interconnection region includes east New Mexico, southwest Colorado, Texas Panhandle, western Oklahoma, and southwest Kansas (Fig. 1). Because several underground natural gas storage facilities currently exist in the area, sufficient availability of air storage reservoirs in the region can be implied.

The wind power duration curves in Fig. 2 show the effect of interconnecting multiple wind farms on aggregate electricity supply. First, the number of hours at maximum, nameplate power decreases as more sites are added to the interconnected system, or array. However, of key importance is the reduction in the number of hours with zero power supply for the 19-site array (only 1 h in a year) compared with that of a single site (15% of the hours in a year). In addition, the intermittency of the interconnected system is reduced [16].

Wind electricity in both models is transported to local/regional markets via high voltage DC (HVDC) lines, with an average transmission distance of 1200 km. The DC power is converted to AC at the local/regional grid interface. Total electricity losses are 3% for 1200 km transmission and 1% for DC–AC conversion. These values are based on the most recent HVDC installations in China by Siemens [17]. The state-of-art HVDC has a nameplate capacity of 7.2 GW with a maximum carrying capacity of 6.4 GW of power.

The assumed efficiency of the 19-site wind array before connecting to the long distance HVDC transmission lines is 87%. The 13% wind power losses are: 3% for wind turbine downtime, 5% for turbine spacing wake effects, 4% for the transmission to the transformer station, and 1% for transformer station power conditioning to uplink the wind power to the HVDC transmission line [18,19]. The above 4% wind power transmission losses are based on a 267 km average distance from the wind farms to the nearest HVDC transformer station or CAES plant (Fig. 3).

The long-distance HVDC transmission system capital cost is $2.4 million per km and includes DC–AC converter station costs [12]. These capital costs "per km" are then converted to capital costs "per watt" of power plant load capacity credit and are included in the capital cost and cost of electricity estimates for the two wind models discussed in Section 4.3. In contrast, the coal power plant

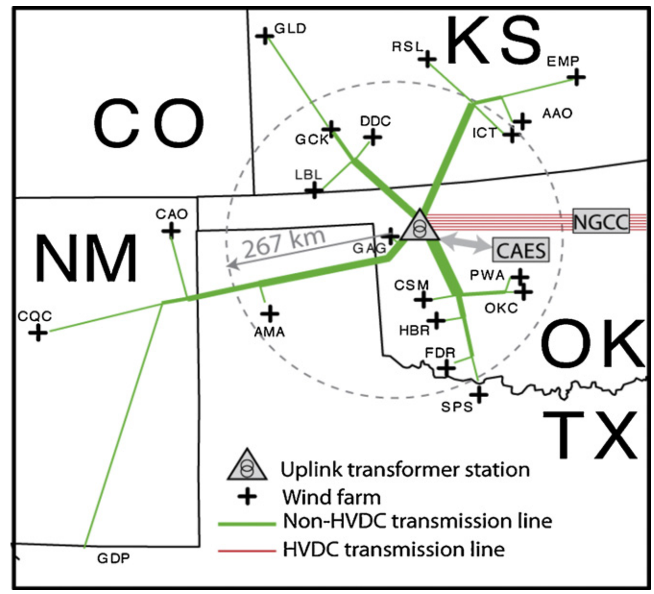


Fig. 3. Schematic of the model wind farm, CAES, and HVDC uplink system. The + marks are the locations of the 19 interconnected wind plants used in this study. The CAES plant and the HVDC transformer station are located in close proximity. The NGCC plant, alternatively to CAES, would be located downwind of the HVDC uplink station.

is located within the local/regional grid and incurs no additional long-distance transmission costs.

In both Wind-NGCC and Wind-CAES models the capacity allocations are scaled to provide a total of 400 MW of baseload capacity credit. The 400 MW size, arbitrarily selected, is within the 300–600 MW range for conventional coal baseload plants. In both models, electricity from the gas turbines is ramped up or down as required to balance out the variable supply of wind power to insure a constant 400 MW power flow to the local grid. In other words, when wind power supply is less than 400 MW, electricity from the gas turbines, with or without compressed air for Wind-CAES and Wind-NGCC respectively, provides the balance.

2.2. Wind-NGCC model

The components of the Wind-NGCC model are a wind farm, a HVDC long-distance transmission system, and a NGCC power plant. The Wind-NGCC model combines wind and NGCC turbines to supply 400 MW of baseload capacity credit. When the supply of wind power is less than 400 MW the balance is supplied by the NGCC plant. The key design issue is to insure a 400 MW supply of electricity to the local grid 90% of the hours of the year and 100% of the hours during summer and winter peak load periods. The wind farm and NGCC plant capacity allocations are presented in Section 4.1.

In the Wind-NGCC model, only wind electricity is transported long-distance via HVDC since the NGCC plant is located within the terminal local electricity transmission network. This means that the variable supply of wind power results in less than maximum capacity utilization of the long-distance HVDC electricity transmission lines. This increases transmission cost, as discussed in Section 4.4.

2.3. Wind-CAES Model

The components of the Wind-CAES model are a wind farm, an air storage reservoir, a CAES power plant, and a HVDC long-distance transmission system. Wind electricity is first delivered to a HVDC transformer station, where it is routed to the HVDC transmission

line and/or to the air storage reservoir. The purpose of the CAES plant is to firm wind electricity and insure a constant flow of contracted baseload electricity over the HVDC line to local/regional electric companies who then distribute the electricity to retail customers. Revenue streams flow back through the integrated system from the retail sale of the Wind-CAES electricity in local markets.

A CAES plant is composed of a conventional gas turbine power plant (the "thermal" component) and an underground compressed air storage facility ("storage" component). CAES plants can be considered a special type of thermal power plants because they are typically equipped with Natural Gas Combustion Turbines (NGCT), but they also allow for storage of excess electricity in the form of compressed air in an underground air storage facility.

CAES plants are a proven technology. There are two CAES plants in current operation: a 290 MW CAES plant operating in Germany since 1978 and a 110 MW CAES plant operating in McIntosh, Alabama since 1991. Both are operated as peak-demand power plants. They purchase inexpensive off-peak electricity at night to compress and store air in an underground reservoir. Later in the day, at times of peak demand, the compressed air is released from the air reservoir to power the NGCT plant, thus generating electricity at a premium retail-price without having to use air compressors as in the conventional combustion turbine plant design. It is noteworthy that the Alabama CAES plant was the only Gulf Coast power plant in operation during Hurricane Katrina. Its underground salt dome is sized to provide 26 h of electricity without recharging the air storage reservoir.

CAES plants have several attributes that are attractive for firming intermittent wind power into baseload power. First, CAES plants have a very rapid startup time because the air entering the turbine's combustion chamber is already compressed. In contrast, conventional combustion turbine plants require a longer startup time because the compressors have to be started and begin compressing air before the air can enter the turbine's combustion chamber. Rapid startup time is a key for fast-response reserve capacity to firm variable wind and solar power.

Second, CAES plants are an excellent means of storing wind electricity. The energy ratio of electricity output from the CAES plant per unit of incoming wind electricity for air compression is between 1.3:1 and 1.6:1 [20], depending on the size and efficiency of the CAES plant. The overall turnaround storage efficiency of CAES plants is about 70%, which compares favorably with other forms of electricity storage such as batteries and pumped hydro plants [10].

Third, the fuel consumption of a CAES plant is 62% less than a conventional NGCT plant and 42% less than a NGCC plant based on the heat rates in Table 1. Two-thirds of the fuel consumed by conventional natural gas power plants is used to power the air compressors to create the desired air density and velocity. When coupled with wind, the CAES compressors are powered by wind energy to store compressed air, thus resulting in a true net reduction in fuel consumption rates. In contrast, if off-peak coal or NGCC power is used to power the compressors for stored compressed air, then the fuel consumption of these power sources have to be taken into account in estimating the net fuel consumption rate of CAES plants. Also, the compressors in CAES plants can be separated from the turbotrain unit and located at the air storage reservoir, which reduces the vibration to the turbotrain and possibly reduces long-term maintenance costs.

And fourth, CAES plants have a low dispatch cost. In competitive electricity markets, power supply is queued by operating or dispatch costs with lowest cost power dispatched first. Because of CAES's low fuel consumption rate (discussed in Section 4.4), the dispatch cost is competitive with NGCC and coal plants [9,10].

The underground compressed air storage facility can be either a depleted natural gas well or a saline aquifer with a depth of 500–700 m. Salt formations are another potential storage medium but are unlikely to be appropriate at the size needed for baseload CAES plants. The distribution of favorable geologic formations for CAES plants (Fig. 1) suggests that there is ample air storage capacity for CAES plants in the U.S. [10]. In particular, numerous underground natural gas facilities already exist in the depleted natural gas fields in the Texas Panhandle, east New Mexico, Oklahoma, and Kansas, which correspond with some of the nation's highest quality wind resources [21,22]. Underground natural gas facilities are also located in aquifers in the upper plains states of Wyoming, Montana, the Dakotas, Nebraska, Iowa, and Minnesota, which are areas with high quality wind resources too [21,22].

For CAES plants, wind electricity is used to power compressors at the underground air storage facility, which is designed to store 525 million kg of compressed air at a maximum pressure of 8274 kPa.[1] When the associated gas turbine plant is in operation, air is released from storage and piped to the gas turbine unit at the rate of 503 kg/s. Therefore, the 525 million kg of stored air capacity supports 290 h of CAES gas turbine operation without any recharging of the air storage reservoir (525×10^6 kg stored air/503 kg/s released air = 290 h). The compressed air released from the storage reservoir is throttled to a constant 6205 kPa inlet pressure to the gas turbine, which corresponds to the gas turbine's inlet air flow rate of 493 kg/s with 2% air loss due to pressure throttling [20].

Before the compressed air enters the turbine combustion unit, the compressed air is routed through a heat recuperator unit where the compressed air is preheated with the exhaust heat from the gas turbine [20]. The application of an exhaust heat recuperator unit reduces the quantity of natural gas required in the air expansion stage of turbine operation. The McIntosh Alabama CAES plant has successfully employed a heat recuperator since the plant began operation.

The power capacity of the CAES plant and the volume of the air storage reservoir are determined by imposing the delivery of 400 MW of electricity (the load capacity credit) to the local grid for 90% of the hours in a year and 100% of the hours during the winter and summer peak load periods. Since only one year of wind data are used in this study, the CAES air storage capacity is oversized with a 30% safety margin to provide an air storage buffer for years with less favorable wind conditions.

The volume of stored compressed air for the operation of the CAES power plant is referred to as "working air." The working air storage capacity of a CAES plant is designed to maintain a positive balance between the quantity of air injected and the quantity of air withdrawn. The air injection rate is contingent on wind electricity production levels and the compressor capacity at the air storage reservoir. The air withdrawal rate is contingent on electricity production levels of the CAES plant. The air storage after N hours of operation (Air_N), in kg of air, is calculated as follows:

$$\text{Air}_N = \text{Air}_0 + \sum_{n=0}^{N} (\text{In}_n - \text{Out}_n) \tag{1}$$

$$\text{In}_n = \frac{(1 - \text{TL}) \times \text{WP}_n - D_n}{E_C} \times \Delta t_n \tag{2}$$

$$\text{Out}_n = \text{PC}_{\text{CAES}} \times \text{AF} \times \Delta t_n \tag{3}$$

where n is the time index (between 0 and N); In_n and Out_n are the air injected and withdrawn during hour n (kg); Δt_n, is the time interval (1 h); WP_n is the actual wind power output (W); TL is the electricity transmission losses between the wind farm and CAES plant compressor station (13%), plus 3% power conditioning losses

[1] The parameters stated in this section are variables that are specific to the performance parameters for the type and size of the CAES power plant modeled in this paper (Table 2).

Table 1
Power plant cost and performance assumptions.[a]

	Capital cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	Nameplate heat rate (MJ/kWh)[b]	CO_2 emissions (g/kWh)[c]
Wind	1837	30.98	0.00		7
CAES[d]	1639	5.00	3.50	4.38	228
NGCC	937	12.76	2.11	7.59	388
NGCT	653	12.38	3.65	11.38	596
Coal conventional	2078	28.15	4.69	9.71	876
Coal IGCC w/CCS[e]	3427	47.15	4.54	11.37	103

	Capital cost ($/km)	O&M expense	Transmission loss rate	DC–AC conversion loss rate
HVDC system	2,392,390	1.0% of capital	2.5%	1%

[a] Wind, NGCC, NGCT, and coal plant cost and performance estimates are from EIA [29, Table 8.2, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies]. CAES cost and performance assumptions are from [20,25]. HVDC system costs are from the EWITS report [12].

[b] All heat rates are expressed at the high heat value (HHV). For natural gas the HHV is about 10% greater that the low heat value (LHV).

[c] CO_2 emission estimates are based on the multiplication of EIA emission factors of 50.29 g/MJ for natural gas consumption and 90.29 g/MJ for coal combustion by the power plant nameplate heat rates [32]. The CO_2 emissions estimate for wind electricity is from Denholm et al. [33]. For the coal integrated gasification combined cycle (IGCC) coal plant with carbon capture and storage (CCS) system, it is assumed that 90% of the CO_2 emissions are captured and stored.

[d] The CAES plant capital cost estimate includes the compressors for the air storage reservoir. The compressor power capacity is a factor of 1.27 greater than the nameplate power output rating of the combustion turbine unit, i.e., the compressor capacity is 1.27 W per 1.0 W of CT power capacity. Also, the air storage cost estimate is $2.80/kWh. This air storage cost metric is calculated by dividing total air storage cost by the total quantity of electricity produced by the CAES plant with one complete air injection/withdrawal cycle. The air storage cost estimate is derived from an EPRI study as reported in Mason et al. with a 40% increase to account for commodity cost increases [25,34].

[e] The Coal IGCC with CCS plants incurs CO_2 transport, storage, and monitoring (TSM) costs. TSM costs are based on a NETL study [35]. CO_2 TSM costs are highly sensitive to pipeline length. For example, if the CO_2 pipeline length is 62 km the total costs are $11.02/t, and if the CO_2 pipeline length is 155 km the costs increase to $27.35/t. For this study, it is assumed that the CO_2 pipeline length is 62 km.

at the compressor/electricity input interface due to voltage fluctuations in wind power supply; D_n is the hourly baseload demand (W); E_C is the specific energy (J/kg) to compress air for underground storage at an average compression pressure of 7239 kPa; PC_{CAES} is the CAES plant capacity (MW); and AF is the airflow rate of 4312 kg air/MWh electricity output and includes 2% air losses due to pressure throttling. Air injection only occurs when there is an excess of wind power produced over the required baseload demand D_n.

The energy consumption rate for air compression, E_C, is estimated with the following adiabatic compression energy formula:

$$W = \frac{[\gamma/(\gamma-1)]p_1V_1[(p_2/p_1)^{\gamma-1/\gamma}-1][(Z_1+Z_2)/2Z_1]}{\eta} \quad (4)$$

where W is the specific compression work (J/kg); γ the specific heat ratio (adiabatic coefficient) of air; p_1 and p_2 are the initial and final pressures (Pa); V_1 the initial specific volume (m^3/kg); Z_1 and Z_2 the gas compressibility factor for initial and final pressures; and η the compressor efficiency [23]. The compressibility factor is estimated by the Redlich-Kwon Equation of State method [24]. A compressor efficiency of 80% is assumed over the 0.1–8.2 MPa range of pressures.

The CAES facility is assumed to employ four-stage, inter-cooled compressors. On average the compressors consume 0.54 MJ/kg of air compressed at an average pressure of 7239 kPa. The corresponding energy ratio of wind electricity going to the compressors per unit of electricity produced by the CAES CT plant is 0.65 kW h-out/kWh-in. Three-stage compression is an option and consumes 0.58 MJ/kg of air compressed at an average pressure of 7239 kPa. The tradeoff between three- and four-stage compression is the effect on total system cost. This study finds a small advantage with four-stage compression.

The air storage facility is assumed to be a porous rock geologic formation such as saline aquifers and depleted natural gas wells. Depleted gas wells are the preferred storage media because the gas extraction history provides extensive knowledge about the geological properties of the reservoir [21,22]. The key components of an air storage facility are the network of air injection and air withdrawal wells to achieve desired air flow rates. The number of injection-withdrawal wells is determined by the geological properities of the storage reservoir such as the porosity, permeability, and water drive characteristics of the porous rock formation.

The capital cost of air storage reservoirs is variable and is driven by the number of air injection-withdrawal wells that are required to suppy a given air flow rate [21,25]. Compressor capacity is another significant cost component of an air storage facility. Compressor capacity is a function of the air injection and air withdrawal rates required to support the CAES plant's power output demands. An average capital cost for a porous rock air storage facility is derived from an EPRI study with costs converted to 2010$ [25]. The capital cost estimate is based on a conservative number of air injection-withdrawal wells (108) and compressor capacity [25].

3. Methods and assumptions

In both Wind-NGCC and Wind-CAES models, the electricity supplied by wind combined with either NGCC or CAES must have the same level of reliability as conventional fossil fuel or nuclear baseload power plants. In addition, capacity specifications are designed to supply a pre-determined quantity of electricity (400 MW) 90% of the hours in a year and 100% of the hours during summer and winter peak load periods. As such, both designs can effectively be considered baseload systems.

The seasonal electricity supply requirement is especially demanding for the Wind-CAES model since there must be a sufficient supply of stored air to meet electricity production requirements under extended periods of low wind conditions [6,8], which generally occur in summer months. This is the first study to date to explicitly evaluate such a stringent requirement on a baseload Wind-CAES system. Finally, both models have a thermal component (i.e., natural gas combustion turbines), and both emit CO_2 but in different amounts, as will be discussed later.

To insure reliability of U.S. electricity supply, statutory reserve capacity requirements currently range from 10 to 20% of assigned operating capacity. Reserve power plants supply electricity when assigned capacity units experience unplanned downtime or when power demand is greater than expected. In this study, reserve natural gas combustion turbine (NGCT) capacity is included in the Wind-NGCC model. In the Wind-CAES model there is no need for a reserve NGCT plant since the CAES plant can function as both capacity credit and reserve capacity, which is demonstrated with the electricity production profile in Section 4.2.

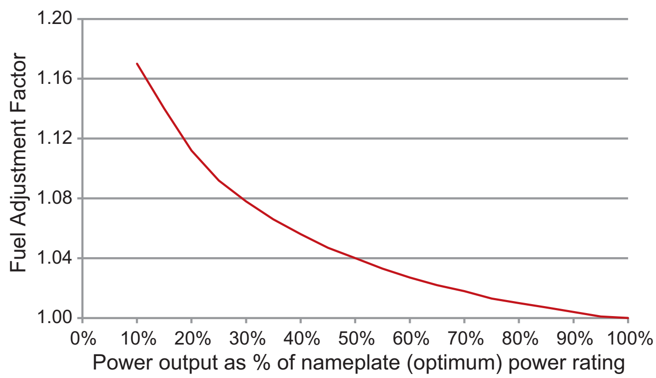


Fig. 4. Power plant heat rate adjustment factors, which are derived from EPRI and Dresser-Rand estimates [26,27].

3.1. Heat rates and spinning reserves

Because wind is naturally variable, neither NGCT nor NGCC plants can operate at their nameplate power ratings at all times, but have to ramp up and down to compensate for the wind intermittency. As such, the "operating" heat rates (i.e., actual fuel consumption rates as opposed to the nameplate heat rates) are not optimal and need to be adjusted based on actual power output levels. Such adjustments are also needed to obtain realistic CO_2 emission estimates.

In this study, fuel consumption estimates are based on the application of heat rate adjustment factors that are derived from EPRI and Dresser-Rand estimates [26,27]. A graph of the heat rate adjustment factors is presented in Fig. 4. The heat rate adjustments are applicable to the Wind-NGCC and Wind-CAES models, but not to the coal model since coal plants are operating at their optimum nameplate rating 24/7. The adjustment factors range from 1.0 at maximum (or nameplate) power output to 1.17 at the minimum power output level of 10%. For example, if the power output of the NGCC or CAES plant is 70% of the nameplate power, then the "operating" heat rate is a factor of 1.02 greater than that at the nameplate power rating.

Another important component in modeling wind power is the time spent by the supporting thermal power plants in spinning reserve mode, i.e., in operational mode but not generating electricity. Studies have profiled the synchronicity of wind supply against load, and the findings imply that thermal power plants operating in spinning reserve mode are required for as much as 20% of the total hours of wind-only electricity supply to insure that there will be an adequate supply of electricity to meet demand (load) [12,28]. Wind forecast error is the primary reason for needing spinning reserve capacity. Wind forecast error is particularly relevant when wind power is at its maximum assigned output and supporting thermal power plants are shut-down to save on costs and fuel consumption.

Hence, in this study it is assumed that supporting thermal plants operate in spinning reserve mode 20% of the hours that wind power is providing the full 400 MW of assigned power to compensate for wind forecast error. When a thermal power plant is in spinning reserve mode, it operates at low power, which is assumed to be 10% of the plant's nameplate power rating with a heat rate adjustment factor of 1.17 [26,27]. Based on the capacity allocations explained later, spinning reserve is applicable to the Wind-CAES model only. Neither the Wind-NGCC nor the coal plant models need it.

In the Wind-NGCC model wind supplies maximum power only 15 h per year, which is 0.2% of the assigned time; thus the supporting NGCC power plant is actually operating 99.8% of the assigned time. Adding spinning reserves to the Wind-NGCC model for such a few hours does not make a significant difference. Similarly, the coal plant is assumed to be operating at its assigned annual capacity utilization factor, which implies no time in spinning reserve mode.

In contrast, the Wind-CAES model has many hours in the year (4267 h) when wind power alone is providing the full 400 MW power supply. This is a consequence of over-sizing wind capacity to provide the required quantity of stored wind power, in the form of compressed air, for the supporting CAES plant (details in Section 4.1). To prevent unexpected drops in wind power below the assigned 400 MW during the hours when wind alone is providing the full power supply, the CAES plant is modeled to operate in spinning reserve mode for 20% of these hours (854 h).

Table 2
List of operating parameters and assumptions.

Wind system level electricity loss rate (from turbines to HVDC/CAES)	13%
NGCC parasitic power loss rate[a]	1.7%
NGCC spinning reserve (h)	0
Reserve NGCT parasitic power loss rate	2%
Reserve NGCT spinning reserve (h)	0
CAES spinning reserve (h)	1577
CAES parasitic power loss rate	2%
CAES air flow from storage to turbine (kg/s)[b]	493
CAES air pressure from storage to turbine (kPa)	6205
CAES energy ratio (CAES kWh out/wind kWh in)[c]	1.54:1
HVDC nameplate capacity (GW)	7.2
HVDC line maximum carrying capacity (GW)	6.4
HVDC line loss rate (per 1000 km)	2.5%
HVDC DC–AC converter station efficiency	99%
Coal conventional annual capacity factor	85%
Coal conventional parasitic power loss rate	5.6%
Coal conventional spinning reserve (h)	0
CAES air storage facility	
Air storage capacity - working air (million kg)	525
Air storage volume - working air at 8274 kPa (million m^3)	5.25
Hours of turbine/generator operation at maximum stored air capacity	290
Air storage facility cost ($/kWh electricity output - 420 MW @ 290 h)	2.8
Efficiency of wind power interconnection to CAES compressors	97%
Compressor to turbine/generator power ratio	1.27:1
Efficiency of air compressors (4-stage intercooled compressors)	80%
Maximum reservoir air pressure (kPa)	8274
Minimum reservoir air pressure (kPa)	6205
Average pressure of compression (kPa)[d]	7239
Energy consumption for air compression (MJ/kg)	0.54
Air losses from pressure throttling[e]	2%

[a] Parasitic power loss is the power consumed by power plants during normal operation. The parasitic power loss estimates are from NETL [36].
[b] The CAES plant operating parameters are for EP&S's 420 MW concept design [20].
[c] Compression energy is derived from Praxair's adiabatic compression formula provided in the text. The compressor efficiency of 80% is a mid-range estimate to take into account the effect of wear and tear prior to servicing.
[d] The air capacity of the storage reservoir is variable, and it is assumed that on average the compressors are pressuring air at the midpoint of the maximum and minimum pressures.
[e] The air loss estimate for pressure throttling is derived from Succar and Williams [10].

3.2. Levelized cost of electricity

Levelized cost of electricity estimates are derived from the cost and performance data presented in Tables 1 and 2. All monetary units are in 2010 U.S. dollars. The financial assumptions for cost of electricity estimates are presented in Table 3.

Levelized cost of electricity estimates are calculated by the net present value, cash flow method. The levelized cost of electricity is the price that generates a constant revenue stream to recover all capital investments and expenses over the capital recovery period.

Table 3
Financial assumptions.

Construction time[a]	Variable by power plant
Capital structure (debt/equity ratio)	55% debt/45% equity
Nominal return on equity	12%
Nominal return on debt	9%
Real discount rate (weighted average cost of capital)	5.4%
Annual inflation rate	3%
Capital recovery period (all plants but wind)	30 years
Capital recovery period for wind plants	25 years
Insurance	0.5% of capital
Property tax	1% of capital
Working capital	10% of annual expenses
Depreciation method	20-year MACRS
Corporate tax rate	39%
Maintenance cost - in years 10 and 20 (all but wind)	5% of initial capital
Maintenance cost for wind plants - occurring in year 12	5% of initial capital

[a] The assumed construction times are: wind plants – 3 years; CAES plants – 3 years; NGCC plants – 3 years; conventional coal scrubbed steam plants – 6 years; coal IGCC with CCS – 6 years.

The net present value, cash flow method is characterized by the formula

$$NPV = \sum_{t=1}^{N} \frac{NCF_t}{(1+k)^t} - I_0 \quad (5)$$

where NPV is the net present value of the investment; NCF_t is the annual net cash flow in year t; k is cost of capital, which is a weighted average cost of debt and equity capital (WACC); $(1+k)^t$ is the discount rate to convert annual net cash flows to their present value in year t, N is the number of years for capital recovery, and I_0 is total capital investment in the project. It should be noted that levelized electricity price estimates are sensitive to changes in financial assumptions.

4. Findings

In the two wind models – Wind-NGCC and Wind-CAES – various parameters (e.g., capacity allocations) and assumptions (e.g., cost of fuels) could easily be changed to evaluate their effects on the overall system efficiency and costs and to identify the optimal solution. In particular, this section focuses on the following results:

(1) capacity allocations;
(2) hourly electricity supply;
(3) fuel consumption and CO_2 emission rates;
(4) capital and electricity costs, with and without a CO_2 tax and with and without sensitivity to the price of fuels (natural gas and coal).

The implications of these findings on the future U.S. electric mix with a high penetration of wind are also presented. Because coal power plants are commonly used for providing baseload power, the capital and electricity costs of the two wind models are compared against those of a conventional baseload coal power plant. The coal power plant has a rated capacity of 400 MW, a fuel efficiency of 37%, and a CO_2 emission rate of 856 g CO_2/kWh [9].

4.1. Capacity allocations

For the Wind-NGCC model, the wind turbine capacity is 482 MW, which enables a wind power supply of 400 MW in periods of maximum wind power production to the local grid interface given all system-level electricity losses. As previously defined, the assumed system-level average electricity losses total to 17% due to: 13% electricity losses as electricity is gathered from individual wind turbines and transported to the uplink transformer station (for an average distance of 267 km); 3% HVDC transmission system loss for an average transmission distance of 1200 km; and a 1% DC–AC conversion loss rate.

The capacity allocations for the supporting NGCC and reserve NGCT plants for the Wind-NGCC model are obtained by assigning wind power a 20% effective load carrying capacity (ELCC). A 20% ELCC for the wind power supply component translates into 320 MW of NGCC capacity and 85 MW of reserve capacity to provide 400 MW of baseload capacity credit. A 20% ELCC is compatible with prior studies for the electricity production profile of wind farms located in high quality wind regimes [12].

The capacity allocation is more complex for the Wind-CAES model since wind power is used for both direct HVDC power supply and indirect stored energy for CAES. The resulting allocation is: 1110 MW of wind capacity; 420 MW of CAES gas turbine capacity; 533 MW of compressor capacity; and 525 million kg of "working air" at the maximum storage pressure of 8274 kPa. The selection of the Wind-CAES capacity allocations are based on the following conditions.

The 420 MW CAES power plant capacity insures delivery of 400 MW of electricity to the local grid under the condition of low wind power supply and HVDC transmission losses. The 525 million kg of stored compressed air enable the 420 MW CAES power plant with an air flow rate of 503 kg/s to operate continuously for 290 h without any recharging of the air storage reservoir. The 1100 MW of wind turbine capacity allow for a positive air storage balance under the lowest summer wind power output conditions. There is no need for reserve plant capacity since the CAES plant is operating well within its annual operational design limits.

4.2. Electricity supply

The mix of electricity supply for the Wind-NGCC and Wind-CAES models are presented in the power duration curves in Fig. 5 (a and b, respectively). The power duration curves present the percentage of hours in a year that a specific power amount can be provided or exceeded. Both wind models supply a constant 400 MW of power 90% of the year. The thermal power plants in both models are assigned maintenance downtime for 10% of the hours in a year, arbitrarily assigned to October 1 to November 6 since Spring and Fall are the low demand periods of the year when power plants are typically scheduled for annual maintenance.

In the Wind-NGCC model (Fig. 5a), the wind farms supply the maximum 400 MW of power only 0.2% of the year, whereas the NGCC plant supplies the maximum 320 MW of power 18% of the year. For the remaining hours of the year, the power supply is a combination of wind power, NGCC power, and reserve NGCT power. Of the total energy supply in the Wind-NGCC model, the wind farm supplies 47%, the NGCC plant supplies 52%, and the remaining 1% is supplied by the reserve NGCT plant. The NGCC plant's annual capacity utilization factor is 89%, and its average power output is 65% of its nameplate power rating.

In the Wind-CAES model (Fig. 5b), the wind farms supply the maximum 400 MW of power 49% of the year, and the CAES plant is supplying its maximum output only 3% of the year. The wind farm supplies 80% of total electricity, and the CAES plant supplies 20%. The Wind-CAES model supplies 400 MW of power to the local grid 94.9% of the hours in a year. With scheduled CAES maintenance downtime in low-demand Spring and Fall months, which are periods of the year when the wind resource is generally high, the wind farms are able to supply 400 MW of power for about half

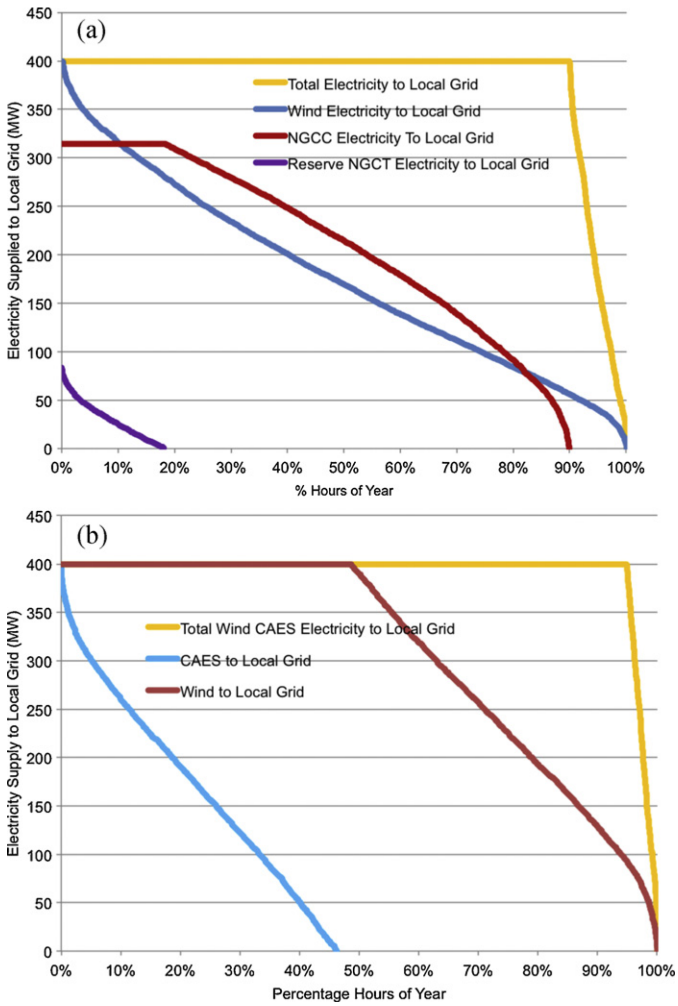


Fig. 5. Wind-NGCC (a) and Wind-CAES (b) power duration curves.

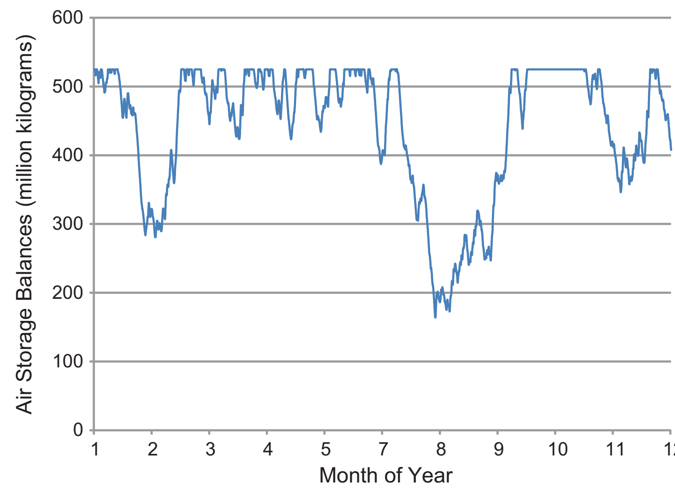


Fig. 6. Air storage balance (million kg) for Wind-CAES model with 290 h of air storage capacity. Notice that there is a 30% air storage margin, 160 million kg, in late summer for years with lowest quality wind conditions.

of the CAES plant scheduled maintenance downtime. Therefore, the actual annual capacity factor for the Wind-CAES model exceeds the 90% requirement.

In the Wind-CAES model, 7% of total wind electricity produced is surplus, i.e., not used. The surplus wind electricity is a result of the air storage reservoir being at maximum capacity during periods of high wind power output. The surplus wind electricity indicates that the system will be able to increase the use of air storage during years with less wind. Alternatively, the surplus can be spilled or used for hydrogen generation and/or battery recharging [30].

Of central importance to the Wind-CAES model is the availability of compressed air for the turbine power plant. The time series of hourly air storage balances over the course of a year for the modeled wind data (Fig. 6) shows minima in late summer with a 30% margin in air storage balances (160 million kg). The 30% air storage buffer is important for the contingency of years with low-wind conditions in summer months, i.e., wind conditions less than the one-year wind data set used in this study. The zero air storage balance in Fig. 6 denotes the reservoir's minimum "working air" capacity.

In summary, both wind models were proven suitable for providing electricity as reliably as traditional baseload power plants. Even though the scenario analyzed here is for 400 MW of load capacity credit, the results can be linearly scaled up to the 300 GW hypothesized by NREL for the 20% wind penetration scenario by 2030 [12]. This will be done in the last section.

4.3. Fuel consumption and CO_2 emission rates

Aggregate fuel consumption rates (in MJ/kWh) are calculated by dividing the amount of natural gas consumed (in MJ) by the aggregate supply of electricity to local grids provided by either wind model (in kWh). Fuel consumption rates are a measure of power plant efficiency. As discussed in Section 3, power plant heat rates have been adjusted for variable output operating conditions, which impact the Wind-NGCC and Wind-CAES models but not the coal model. Also, the Wind-CAES model adjusted heat rates include the time the CAES plant is operating in spinning reserve mode, which is 854 h of the year.[2]

The Wind-CAES model has by far the lowest fuel consumption rate (Fig. 7a): 1.03 MJ/kWh, which is about 4 times lower than Wind-NGCC's (4.22 MJ/kWh) and about 9 times lower than coal's (9.71 MJ/kWh). In other words, the energy efficiency of the Wind-CAES model is dramatically better than that of any other system. Also, the Wind-NGCC's cost of electricity is more sensitive to increases in natural gas cost. Therefore, future natural gas supply and prices are important in evaluating the two wind models.

The aggregate CO_2 emission rates are calculated by dividing the total CO_2 emissions in a year (in grams) by the aggregated electricity produced by the wind models in a year (in kWh). The CO_2 emission estimates also include heat rate adjustments and spinning reserve for the Wind-NGCC and Wind-CAES models. Again, the Wind-CAES model appears to be the best option, with only 61 g CO_2/kWh, versus 216 g CO_2/kWh for Wind-NGCC and 876 g/kWh for conventional baseload coal plants (Fig. 7b). Both wind models have significantly less CO_2 emissions than conventional baseload coal plants (75% less for Wind-NGCC and 93% less for Wind-CAES). If the U.S. is to achieve an 80% reduction in CO_2 emissions by 2050 [31], wind power, especially if coupled with CAES, can play an important role since 80% of CO_2 emissions in the power sector are from conventional coal power plants.

4.4. Cost analysis

Cost and performance assumptions are presented in Tables 1–3. The Wind-CAES system has the highest capital cost: $7186/kW,

[2] We assume that the CAES plant is in spinning reserve mode 20% of the hours that wind is providing the full 400 MW of assigned electricity [12,28]. Wind power supplies 400 MW of electricity 4267 h in the year, and 20% is 854 h.

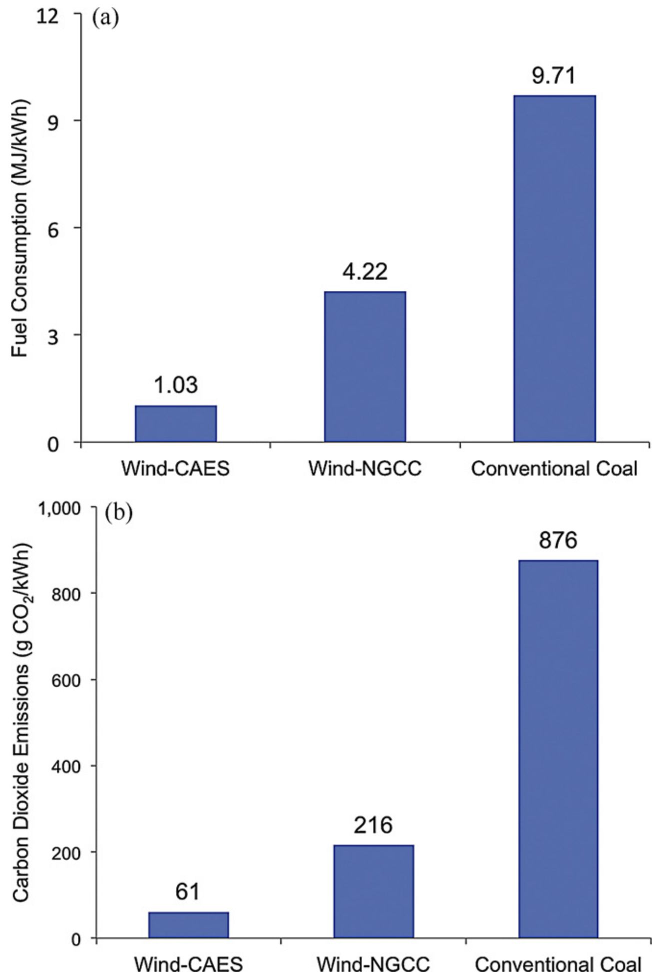


Fig. 7. For each per kWh of baseload electricity supplied to local grid, the figures show (a) aggregate energy consumption rate (MJ per kWh) and (b) aggregate carbon dioxide emission rate (g of CO_2 per kWh).

which is \$6737/kW for Wind-CAES capacity credit and \$449/kW for the HVDC system (Fig. 8). In comparison, the total capital cost of the Wind-NGCC system is \$3413/kW of capacity credit with the same \$449/kW for the HVDC system. In contrast, the capital cost of a conventional coal plant is \$2078/kW. HVDC system costs are

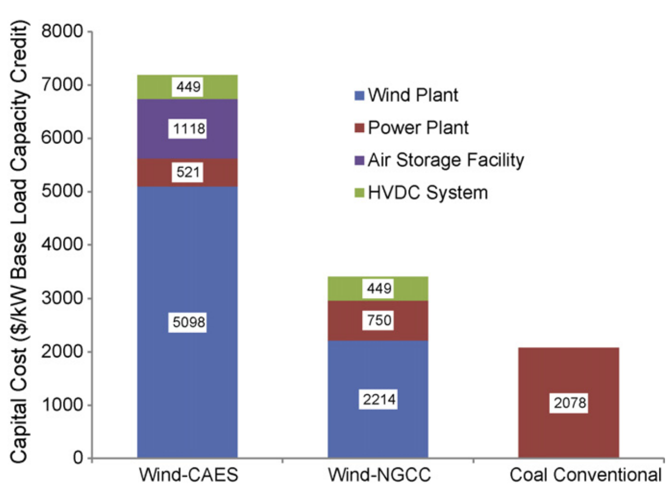


Fig. 8. Capital cost components of the Wind-NGCC, Wind-CAES, and coal models. Compressor cost for the Wind-CAES model is included in the air storage facility since the compressors are assumed separate from the CAES CT plant's turbotrain.

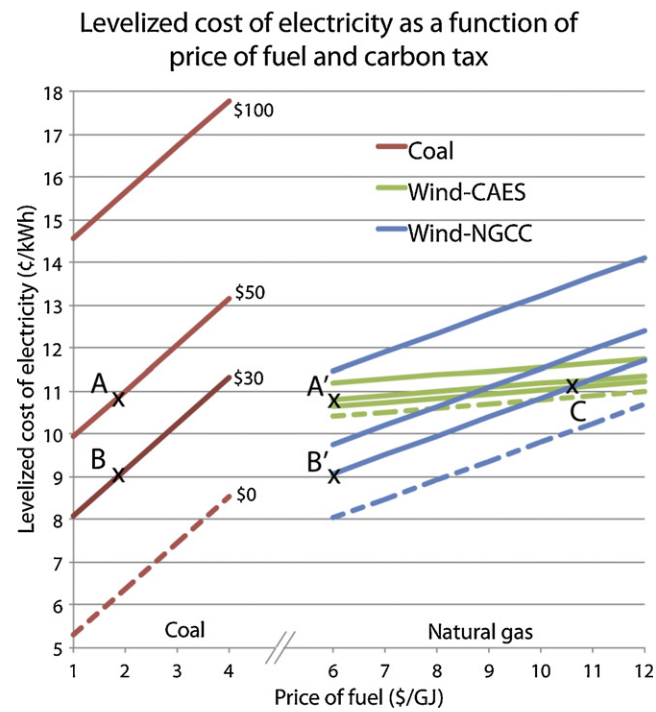


Fig. 9. Levelized cost of electricity (¢/kWh) from coal, Wind-NGCC, and Wind-CAES as a function of price of fuel (\$/GJ, either coal or natural gas) for various carbon taxes (none, \$30, \$50, and \$100 per metric ton of CO_2). Pair A-A′ indicates cost parity between coal and Wind-CAES (at ~11 ¢/kWh with coal at ~\$2/GJ, natural gas at ~\$6/GJ, and a carbon tax of \$50/t-CO_2), B-B′ between coal and Wind-NGCC (~9 ¢/kWh with carbon tax of \$30/t-CO_2), and point C between Wind-NGCC and Wind CAES (~11 ¢/kWh with natural gas at ~\$10.5/GJ and carbon tax of \$30/t-CO_2).

not added to the coal power plant because in general the transmission infrastructure already exists since new coal power plants are expected to be built in proximity to the ones being replaced.

The cost of electricity is the price paid at the local grid interface by local/regional electric utilities. It includes all HVDC transmission system costs from the point of production to the local grid interface. The baseline fuel costs used in the cost of electricity calculations are a natural gas price of \$6/GJ and a coal price of \$1.84/GJ.

Like capital costs, the cost of electricity is highest for the Wind-CAES model, \$0.104/kWh, whereas for the Wind-NGCC model it is \$0.080/kWh (Fig. 9, dashed lines). The relative cost contribution of the HVDC transmission system is less than half in the Wind-CAES than in the Wind-NGCC model (\$0.006/kWh and \$0.013/kWh, respectively). Since only intermittent wind electricity is distributed over the HVDC system in the Wind-NGCC model, the utilization factor of the HVDC transmission for the Wind-NGCC model is 47%, while for the Wind-CAES model it is 100%. Thus the higher cost of transmission in the Wind-NGCC is explained by its lower efficiency in transmission utilization.

In marked contrast, the cost of electricity for conventional coal plants is much lower than both wind models: \$0.062/kWh, which is \$0.018/kWh and \$0.042/kWh less than the cost of electricity for the Wind-NGCC and the Wind-CAES, respectively. Because coal prices are so much less than natural gas prices per unit of energy, the cost of coal electricity remains lowest even with large increases in coal prices.

Other important factors that affect the cost of electricity in both wind models and in the coal plant model are the sensitivities to fuel prices and to CO_2 taxes. Fuel prices are not expected to remain constant at their current low prices (~\$1.84/GJ for coal and ~\$6/GJ for natural gas) over the thirty-year capital recovery period for new power plants. A CO_2 tax has been proposed as an effective method to make the cost of electricity from low-CO_2 power plants become

competitive against more polluting, but cheaper, coal power plants [37].

Both sensitivities are considered simultaneously in Fig. 9, which shows cost of electricity for all three models as a function of both fuel price (coal or natural gas) and CO_2 tax. As the price of fuel increases, so does the cost of electricity, but at different paces: the Wind-CAES model is the least sensitive and the coal plant model is the most sensitive. Similarly, as the CO_2 tax increases, so does the cost of electricity.

The cost of electricity sensitivity analysis to CO_2 tax levels with constant low-end fuel prices of $1.84/GJ for coal and $6/GJ for natural gas indicates that the CO_2 tax level to create cost of electricity parity between the Wind-NGCC and coal plant models is ∼$30/t (pair B-B′ in Fig. 9). With a $30/t CO_2 tax, cost of electricity parity between the Wind-CAES and Wind-NGCC models occurs with a natural gas price of $10.55/GJ (point C in Fig. 9). The cost of electricity parity between the Wind-CAES and coal model with a $30/t CO_2 tax occurs with a coal price of $3.45/GJ.

The minimum CO_2 tax to create cost of electricity parity between the Wind-CAES and coal plant models is ∼$50/t (pair A-A′ in Fig. 9). With a $50/t CO_2 tax, cost of electricity parity between the Wind-CAES and Wind-NGCC models occurs with a natural gas price of $9.08/GJ and between the Wind-CAES and coal model occurs with a coal price of $1.91/GJ. Overall, the Wind-CAES model is almost insensitive to fluctuations in natural gas price and CO_2 tax rates because of its low aggregate fuel consumption rate. On a final note, a CO_2 tax of $100/t is sufficient to create cost of electricity parity between the Wind-CAES and Wind-NGCC models at today's $5–6/GJ natural gas prices (Fig. 9, top lines).

Another option to reduce coal plant CO_2 emissions is with CO_2 capture and storage (CCS) systems. While it is beyond the scope of this study to fully evaluate coal power plants with CCS, it is appropriate to review some findings. Coal plants with CCS compared with conventional coal plants have greater capital costs, lower operating efficiency in terms of fuel consumption, much greater parasitic power losses (25%) [36], and much greater fixed O&M expenses ($45/kWh) [29]. In addition, the CO_2 transport, storage, and monitoring (TSM) costs need to be taken into account. Such costs have been estimated by NETL [35] to range from $5.51/t to $11.02/t with CO_2 pipeline distances of 31 km and 62 km respectively, which must be included in the cost of electricity calculation. In summary, NETL [35] indicated that total TSM costs for a 400 MW power plant are about the same as the cost estimates for the CAES facility used in this study. Therefore, the cost of electricity for coal plants with CCS will be relatively expensive in comparison with either the Wind-NGCC or Wind-CAES model.[3]

4.5. Implications for high wind penetration scenarios

One of the objectives of this study is an assessment of the indirect effects of using wind electricity on U.S. natural gas consumption. Recent studies have focused on adopting wind energy at a 20% penetration level by 2030 [1,12], thus generating ∼800 TWh (20% of the ∼4000 TWh of today's U.S. electricity production) from wind [12,14]. The results from the previous sections are scaled up to provide these 800 TWh of electricity by the Wind-NGCC and the Wind-CAES models.

For the Wind-NGCC model, 88 billion cubic meters of natural gas per year are needed to supply 800 TWh of electricity to local grids. Given that total U.S. natural gas consumption is about 638 billion cubic meters [14], the 88 billion cubic meters represent a 14% increase in total U.S. natural gas consumption. In contrast, the Wind-CAES model would require only 22 billion cubic meters of natural gas to supply 800 TWh of electricity to local grids, which is a 3.4% increase in total U.S. natural gas consumption. It is realistic to assume that a 14% increase in total U.S. natural gas consumption will have a larger impact on natural gas supplies and prices nationwide than the 3.4% increase with Wind-CAES.

The critical issue in planning power plants today is forecasting long-term U.S. natural gas supply and prices. A large source of U.S. natural gas supply is being developed in shale gas plays. While it is obvious that at present there is supply abundance from shale gas, the issue is the cost of natural gas supply post-2030. Natural gas prices post-2030 are important in assessing the effect of natural gas prices on the post-amortization value of electricity supply.

Natural gas from shale gas plays is abundant, and shale gas production has turned around the reduction in natural gas supply from conventional sources that occurred in 2001. However, an understanding of shale gas production and cost dynamics is just beginning to emerge [38–41]. Another important source of long-term U.S. natural gas supply is Alaska North Slope (Arctic) gas, which is constrained by the need for multi-thousand mile pipelines. Also, natural gas supply from frozen natural gas hydrates is speculative at present – in terms of cost and the ability to prevent the release of unacceptable levels of methane into the atmosphere. In conclusion, natural gas supply and prices are not known with certainty post-2030, and more research is needed to evaluate long-term natural gas supply and cost trajectories.

Also of interest is the effect of a complete replacement of coal baseload power plants with the two wind models. At present, coal power plants produce ∼1800 terawatt-hours (TWh) of baseload electricity in the U.S. [14]. If Wind-NGCC or Wind-CAES plants are selected to replace coal baseload power plants, then their impact on U.S. natural gas markets is expected to be high because natural gas consumption would increase by either 31% (199 billion cubic meters for Wind-NGCC) or 8% (49 billion cubic meters for Wind-CAES). When a long-term view is taken, the Wind-CAES model appears to be the prudent choice.

Finally, societal costs associated with replacing conventional coal power plants with the two wind models can be evaluated in terms of the cost of electricity differentials between the electricity produced by conventional coal plants and the two wind models. Assuming no CO_2 tax and baseline fuel prices, the low cost of electricity differentials are +$0.028/kWh if switching from coal to Wind-NGCC electricity and +$0.042/kWh from coal to Wind-CAES. If all 1800 TWh of coal electricity are replaced, then the societal cost is $50 billion per year for Wind-NGCC and $76 billion per year for Wind-CAES. These costs are only 0.4% and 0.6% of the U.S. $13 trillion GDP, respectively.

5. Conclusions

The U.S. has an abundant supply of high quality, onshore wind resources that can be developed as an economically viable source of baseload electricity. However, the transformation of variable wind electricity into a firm supply of baseload electricity requires the addition of costly backup thermal power plant capacity. This study evaluates two types of backup thermal power plant capacity that can be used to firm variable wind electricity supply: (1) natural gas combined cycle power plants, the Wind-NGCC model; and (2) compressed air energy storage turbine power plants, the Wind-CAES model.

In summary, the Wind-NGCC model provides the lowest capital cost and cost of electricity at current natural gas prices. However,

[3] Using the EIA cost and operating parameters for a coal IGCC with CCS plant ($3477/kW), the NETL CO_2 TSM cost of $5.51/t for a 31 km CO_2 pipeline, the NETL 25% parasitic power loss rate, and the financial assumptions in Table 3, the cost of electricity for coal IGCC with CCS plants is greater than the cost of electricity estimates for the Wind-CAES model in Fig. 9 over the complete range of coal prices.

and this is important, if U.S. natural gas supply/demand dynamics are expected to be out-of-balance post-2030, then the Wind-CAES model becomes the cost competitive choice. Natural gas prices for electric power plants need to be above $10.55/GJ in the 2030–2040 timeframe to economically justify making the high capital expenditures for the Wind-CAES model today. At the current low natural gas prices of $5–6/GJ for electric power generators, a CO_2 emissions tax of $90–100/t is required to create cost of electricity parity between the Wind-CAES and Wind-NGCC models.

Since natural gas supply and cost dynamics post-2030 are uncertain with the present knowledge base, a prudent decision is to begin the process of preparing for the large-scale adoption of coupling wind farms to CAES plants. The first step is to plan the location of HVDC transformer stations for the long-distance transmission of wind power by identifying the most suitable areas for air storage facilities in the highest quality wind regions of the Midwest. Large air storage reservoirs centrally located within a 400 km radius of high quality wind resources can be the gathering point for CAES plants and the HVDC transformer stations, which uplink firm baseload quality wind-CAES electricity onto the long-distance HVDC transmission lines.

From a short-term policy perspective with blinders in regards to future natural gas and CO_2 emissions reduction policy, it is easy to discard the Wind-CAES model. On the other hand, from a long-term policy perspective taking into account future natural gas supply/demand dynamics and CO_2 emissions reduction policy, it is much harder to reject the Wind-CAES model. The strength of the Wind-CAES model is the very low aggregate fuel consumption rate and the corresponding low CO_2 emissions rate. The Wind-CAES model is a sure means of insulating future electricity prices from natural gas price volatility and achieving a >80% reduction in power plant CO_2 emissions by 2050 to mitigate climate change.

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